Decision 17-02-007 February 9, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-006
(NOT CONSOLIDATED)	
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005 (Filed July 1, 2015)
And Related Matters.	Application 15-07-007 Application 15-07-008

DECISION ON TRACK 2 DEMONSTRATION PROJECTS

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DECISION ON TRACK 2 DEMONSTRATION PROJECTS

Summary

This decision addresses Track 2 Demonstration Projects C, D and E proposed by Pacific Gas and Electric Company (PG&E) in Application (A.) 15-07-006, Southern California Edison Company (SCE) in A.15-07-002, and San Diego Gas & Electric Company (SDG&E) in A.15-07-003, as well as the demonstration projects proposed by Center for Sustainable Energy, Community Environmental Council, and Bloom Energy. PG&E's proposed Demonstration Projects C and D are approved. SCE's proposed Demonstration Projects C and D are approved. SDG&E's proposed Demonstration Projects C and E are approved. Approved Demonstration Projects are subject to certain conditions and modifications. The other proposed projects are not approved. This decision addresses current Track 2 issues; these proceedings remain open for revised Track 2 proposals and consideration of other issues.

1. Background

The Order Instituting Rulemaking (OIR) that opened Rulemaking (R.) 14-08-013 included the question:

> 10) Should the DRPs [Distribution Resources Plans] include specific measures or projects that serve to demonstrate how specific types of DER [Distributed Energy Resources] can be integrated into distribution planning and operation? If so, what are some examples that IOUs [Investor Owned Utilities] should consider? (OIR at 7.)

The February 6, 2015 *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning* (Guidance Ruling) directed the utilities to propose DER-focused demonstration projects, and provided more detailed guidance regarding what should be included in those

demonstration projects. (Guidance Ruling, Attachment 1 at 5-7.) The utilities submitted their proposed demonstration projects in the applications filed on July 1, 2015, and in supplemental filings on June 17, 2016.

The January 27, 2016 *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, Including Deconsolidation of Certain Proceedings and a Different Consolidation of Other Proceedings* (Scoping Memo) identified the primary focus of Track 2 as being the design and authorization for Demonstration Projects C, D and E.[1] (Scoping Memo at 8.)

> The Demonstration Projects were described by the Scoping Memo
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> Project C: Demonstrate DER Locational Benefits. This project will validate the ability of DER to achieve net benefits consistent with the LNBA [Locational Net Benefits Analysis].
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> Project D: Demonstrate Distribution Operations and High Penetrations of DERs. This project calls for the utilities to integrate high penetrations of DER into their distribution planning operations. The utilities must: a) assess locational benefits and values of DER at the substation level using ICA [Integrated Capacity Analysis] and LNBA across multiple circuits; b) demonstrate the operations of multiple DER in concert; c) coordinate operations with third parties and customers; d) develop and explain the methodology for selection of DER types used in the project; and e) utilize both third-party-owned and utility-owned resources.
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> Project E: Demonstrate a microgrid where DERs (both customer-owned and utility-owned) serve a significant portion of customer load and reliability services. This project will demonstrate the use of a DER management system for controlling

[1] San Diego Gas & Electric Company (SDG&E) had originally proposed an additional Demonstration Project F, but that proposal is no longer under consideration. Demonstration Projects A and B were addressed in Track 1, and were authorized by an Assigned Commissioner's Ruling issued on May 2, 2016.

> the resources. The project will develop, document, and implement a methodology for construction and operation/dispatch of the DER portfolio. The project will include both third-party-owned and utility-owned resources. (*Id.* at 8-9.)

A May 17, 2016 ruling modified the schedule for Track 2, provided the parties an opportunity to submit revised proposals on June 17, 2016, set workshops for June 28 and 29, 2016, and allowed for post-workshop comments. Pursuant to a July 6, 2016 e-mail ruling, post-workshop comments were filed on July 22, 2016 and reply comments on July 29, 2016. In their July 29, 2016 reply comments, the Commission's Office of Ratepayer Advocates (ORA) requested evidentiary hearings. Evidentiary hearings were held on August 10 and 11, 2016, and post-hearing comments were filed on August 26, 2016.

2. Procedural Issues

SDG&E filed a motion to withdraw its proposed Demonstration Project F,[2] which was granted during the evidentiary hearings. (Transcript, Vol. 1 at 4-5.) SDG&E's proposed Demonstration Project F is no longer under consideration in this proceeding at this time.

3. Discussion

3.1. Demonstration Project C

Demonstration Project C is intended to demonstrate DER locational benefits. This project will validate the ability of DER to achieve net benefits consistent with the LNBA. (Scoping Memo at 8.)

[2] *Motion To Withdraw Optional Demonstration Project F Of San Diego Gas & Electric Company*, filed on July 28, 2016.

3.1.1. Pacific Gas and Electric Company (PG&E)

PG&E initially proposed to use its Chico 12 kilovolt (kV) Distribution Planning Area (DPA) as the site for its Demonstration Project C. (PG&E June 17, 2016 Revised Proposal at A-6-7.)

ORA appeared generally supportive of PG&E's choice of the Chico DPA for Demonstration Project C. Specifically, ORA liked that the area chosen for PG&E's Demonstration Project C aligns with its proposed area for Demonstration B. (ORA July 22, 2016 Comments at 9.) The Utility Reform Network (TURN) largely focuses its comments on Demonstration Project C on what it calls the "non-DER procurement" costs, and recommends that for each utility those costs should be under $2 million. (TURN July 22, 2016 Comments at 5-6.) PG&E's proposed non-DER procurement costs were $1.75 million. As a result, TURN observed that: "Only PG&E provided total costs (for non-DER procurement) that appear reasonable and within the scope of what is necessary for Demo C." (TURN July 22, 2016 Comments at 5.) Other parties either generally supported or were silent on PG&E's proposed Demonstration Project C. (*See*, e.g. Green Power Institute (GPI) July 22, 2016 Comments at 2.)

The proposed decision found that "PG&E appears to have chosen a reasonable location with reasonable costs," and recommended approval of PG&E's proposed Demonstration Project C. In its comments on the proposed decision, however, PG&E indicated that its proposed location for Demonstration Project C is no longer viable due to "reduced equipment loadings," and requests authorization to submit a revised Demonstration Project C at a new location. (PG&E Comments on PD at 2.) Accordingly, PG&E's proposed Demonstration Project C is not approved.

PG&E is ordered to file and serve Comments, within 30 days of the date of this decision, requesting approval for a new location for its Demonstration Project C. PG&E's filing should contain the same level of detail as provided for its original proposed location. PG&E shall present a webinar on the details of its new location, noticed to the service list, no later than 20 days from the date of this decision. Other parties may file and serve Reply Comments no later than 30 days after PG&E's service of Comments proposing a new location for its Demonstration Project C.[3]

3.1.2. Southern California Edison Company (SCE)

SCE describes its proposed Demonstration Project C as follows:

> Since the initial DRP filing, SCE has studied the PRP [Preferred Resource Pilot] region and identified the new El Toro Marine base area residential development as the most suitable location within this region for the Demonstration C project. This area is served by four circuits (Hine, Paragon, [fn. omitted] Keeline and Elden) from the Irvine substation. The additional load expected from the new development and the growing region is anticipated to drive the need for traditional distribution system upgrades to address circuit capacity and duct bank heating issues. SCE believes that this situation serves as a good field opportunity to test the ability of DERs to achieve net benefits consistent with the LNBA methodology. (SCE June 17, 2016 Comments at 3-4.)

Parties are generally supportive of SCE's proposed Demonstration Project C. (*See*, e.g., GPI July 22, 2016 Comments at 2, Environmental Defense Fund (EDF) July 22, 2016 Comments at 3.) The Commission appreciates that SCE has chosen an area that has a high anticipated load growth and that SCE will

[3] While PG&E has 30 days to file Comments requesting approval for a new location, we encourage PG&E to file earlier (if possible), and to work with other parties to resolve any concerns about the proposed new location.

leverage third-party resources already acquired to support the PRP to the extent possible.

At the same time, however, SCE's cost estimate for its Demonstration Project C ($9.3 million, including $6.5 million for "equipment and services") is higher than the cost of PG&E's and SDG&E's Demonstration Project C proposals. TURN argues that SCE's "equipment and services" costs are inflated and not justified, and are unnecessary to achieve the goals of Demonstration Project C. (TURN August 26, 2016 Comments at 2.) TURN has proposed a $2 million non-procurement cost cap for all utilities for Demonstration Project C. (*Id*.)

SCE has not adequately explained the basis for its costs for Demonstration Project C, particularly its high "equipment and services" costs. We cannot find those costs to be just and reasonable. If, for calculation purposes, we applied TURN's recommended $2 million cap to SCE's "equipment and services" costs (a reduction of $4.5 million from SCE's proposed budget of $6.5 million), and we reduce SCE's proposed other costs by the same proportion, this would result in a total budget of just under $3 million, compared to SCE's proposed budget of $9.3 million.[4] Accordingly, SCE's proposed Demonstration Project C is approved, but with a cap on non-procurement costs of $3 million.

3.1.3. SDG&E

SDG&E initially proposed to use two circuits for its Demonstration Project C: Circuit 701 connected to Mission Substation, and Circuit 470 connected to

[4] Those other costs are: Design and Engineering $850,000, DER Deployment Management $650,000, Measurement & Validation (Data Analysis) $850,000 and Project Management $450,000, which total $2.8 million. (SCE's June 17, 2016 Comments at 12.) Reducing these costs proportionately to the reduction in the "equipment and services" costs results in a total of $860,000.

Felicita Substation. According to SDG&E, Circuit 701 is highly loaded, and already has a large number of smart inverters connected to the circuit as a result of a separate smart inverter pilot project, while Circuit 470 had a forecasted capacity deficiency due to load growth in the area, and is the same circuit that SDG&E has designated for Demonstration Project B. (SDG&E June 17, 2016 Responses, Attachment 1 at 5-6.)

TURN, while expressing general support for Demonstration Project C, criticizes the cost and the utility-owned storage component of SDG&E's proposal. TURN recommends a cost cap of $2 million per utility in non-procurement costs for Demonstration Project C, and notes that without the utility-owned storage component, SDG&E's proposal would cost $1.8 million. (TURN July 22, 2016 Comments at 5.) The utility-owned storage proposed by SDG&E would cost $4.6 million, for a total cost of $6.4 million, leading TURN to question whether SDG&E's proposal is consistent with the guidance that the utilities use a "minimum-cost DER portfolio." (*Id.* at 5-6.) TURN also questions whether SDG&E's proposal to add additional utility-owned storage is consistent with the guidance that Demonstration Project C employ services from customer and/or third party DERs. (*Id.* at 6.)

While in general SDG&E's proposed Demonstration Project C is reasonable, we agree with TURN that the inclusion of an overly-large utility-owned storage component is inappropriate, as in this proceeding the Commission is looking for a more technology-agnostic approach, and third-party owned storage or other DER resources may turn out to be more cost effective. Accordingly, we remove the $4.6 million for utility-owned storage from the non-procurement budget for Demonstration Project C.

The proposed decision recommended approval of SDG&E's proposed Demonstration Project C, but in its comments on the proposed decision, SDG&E stated that because of a change in forecasted thermal overload, Circuit No. 470 (one of two circuits proposed for Demonstration Project C) no longer fits the criteria for Demonstration Project C. (SDG&E Comments on PD at 5.) Based on updated forecasts, SDG&E proposes to use Circuits 295, 298, and 597, fed from San Marcos Substation, rather than Circuit 470. According to SDG&E, these circuits are located in the same Distribution Planning Area that was used for Demonstration Project B. (*Id.*) SDG&E does not provide adequate on-the-record information for us to approve the use of these new circuits at this time. Accordingly, SDG&E's use of Circuit 701 for its Demonstration Project C is approved, but Circuit 470 is not approved.

SDG&E is ordered to file and serve Comments, within 30 days of the date of this decision, requesting approval for new locations for its Demonstration Project C. SDG&E's filing should contain the same level of detail as provided for its original proposed location. SDG&E shall present a webinar on the details of its new location, noticed to the service list, no later than 20 days from the date of this decision. Other parties may file and serve Reply Comments no later than 30 days after SDG&E's service of Comments proposing new locations for its Demonstration Project C.[5]

[5] While SDG&E has 30 days to file Comments requesting approval for new locations, we encourage SDG&E to file earlier (if possible), and to work with other parties to resolve any concerns about the proposed new locations.

3.1.4. Schedule

A number of parties were critical of the utilities' proposed schedules for implementing Demonstration Project C. In particular, they argued that the timelines proposed by the utilities were far too lengthy, and that it is important to obtain information from Demonstration Project C results earlier than would occur under the utilities' timeline. (*See*, EDF July 29, 2016 Comments at 2, Clean Coalition July 29, 2016 Comments at 3, Vote Solar August 26, 2016 Comments at 2.)

Because Demonstration Project C is intended to validate the ability of DER to achieve net benefits consistent with the LNBA, getting timely results from Demonstration Project C is in fact a key foundational step. Accordingly we will expedite the implementation of Demonstration Project C, including requiring the utilities to commence the projects within 30 days of approval of this decision, leveraging existing DERs first (both utility-owned and non-utility-owned) before procuring new DERs, an expedited procurement and approval process for new DERs, and setting a schedule for the timely filing of interim and final reports.

Assuming construction of new DERs is needed, this schedule requires the solicitation process to be complete no later than 10 months from approval of this decision, at which time the utilities shall file their contracts for approval. The schedule also requires the utilities to file three progress reports after commencement of data gathering for the projects. The utilities are directed to work with Energy Division to develop the content of these reports, and these reports shall be filed with Energy Division as Information-Only filings and served on the appropriate service list(s). The complete revised schedule for Demonstration Project C is attached as Appendix A.

3.2. Demonstration Project D

The Scoping Memo for this proceeding described Demonstration Project D as follows:

> Demonstrate Distribution Operations and High Penetrations of DERs. This project calls for the utilities to integrate high penetrations of DER into their distribution planning operations. The utilities must: a) assess locational benefits and values of DER at the substation level using ICA and LNBA across multiple circuits; b) demonstrate the operations of multiple DER in concert; c) coordinate operations with third parties and customers; d) develop and explain the methodology for selection of DER types used in the project; and e) utilize both third-party-owned and utility-owned resources. (Scoping Memo at 8.)

3.2.1. PG&E

PG&E's proposed Demonstration Project D is described as follows:

> The proposed location for this demonstration is PG&E's Huron Substation, which is located within PG&E's Gates DPA. Huron Substation was selected due to its high penetration of DERs against this area's distribution capacity. […]
>
> Under projected 2020 peak demand conditions, the Huron distribution transformer is projected to overload up to 20% of the thermal capacity during summer months, while minimum demand conditions coupled with peak PV generation output would cause the Huron transformer to overload in the reverse flow direction during winter months.
>
> Furthermore, this area was selected due to its unique loading profile that is forecast to resemble the "duck curve" that includes high distributed generation output during peak solar production hours and high peak demand during the evening hours. (PG&E June 17 Revised Proposal at A-14.)

ORA initially expressed concern about PG&E's proposed Demonstration Project D, particularly that PG&E had not provided adequate information about

its proposal. (ORA July 22, 2016 Comments at 26-29, 34-36.) Subsequently, ORA indicated that its concerns were addressed at the evidentiary hearings, and accordingly ORA supports approval of PG&E's Demonstration Project D. (*See*, ORA Comments on PD at 3.)

TURN argues that PG&E's (and SDG&E's) proposed Demonstration Project D requires additional evaluation to ensure coordination with existing DER deployment and pilot projects. (TURN July 22, 2106 Comments at 7.) GPI, however, conditionally supports PG&E's proposed Demonstration Project D. (GPI July 22, 2016 Comments at 2, 16.)

The cost of PG&E's proposed Demonstration Project D is $2.1 million plus DER procurement costs. (PG&E July 22, 2016, Attachment 1.) This is the lowest total cost of any of the utility proposals for Demonstration Project D (SCE's proposal has a lower incremental cost), and in general PG&E's proposal is consistent with the Commission's guidance. PG&E's proposed Demonstration Project D (and proposed schedule) is approved.

The Commission agrees with ORA's recommendations that the utility leverage existing RD&D projects to minimize project costs and accelerate learnings. Existing DERs are to be utilized before new procurement is made.

3.2.2. SCE

SCE originally proposed to use its Johanna Jr. substation area for its proposed Demonstration Project D, but later determined that that substation area by itself had insufficient DERs to meet the high penetration requirement; accordingly SCE expanded its proposal to include the adjacent Camden substation. (SCE June 17, 2016 Comments at 17-18.)

SCE further describes its proposal:

> Demonstration D would consist of telecommunication and control systems equipment to forecast, monitor and control high penetration of DERs. The deployed system would demonstrate how to properly operate multiple DERs in concert. For this demonstration SCE expects to have a mix of customer, utility and third-Party owned DERs. (*Id.* at 18.)

SCE's proposal also utilizes its existing Integrated Grid Project (IGP) that is funded through the Electric Program Investment Charge (EPIC). As a result, SCE's proposed Demonstration Project D has low incremental non-procurement costs:

> As noted in the response to Question No. 7, all SCE activities and implementation costs unrelated to third-party DER procurement (i.e., all SCE capital expenditures and O&M [Operations and Maintenance] expenses) will be executed as part of the IGP, and therefore will leverage the existing IGP funding from the EPIC program. Thus, SCE currently anticipates zero incremental funding required for SCE capital expenditures and O&M costs. (SCE June 17, 2016 Comments at 30.)

Other parties expressed some concern about the details of SCE's proposed Demonstration Project D, such as GPI's concern that SCE's use of existing demonstration projects and pilots within its Demonstration D area and the corresponding "fractured nature" of the funding may somehow inhibit SCE's ability to manage or get useful information from the multiple DERs. (GPI July 22, 2016 Comments at 17.) But otherwise, there is no significant opposition to SCE's proposed Demonstration Project D.

Given its low incremental cost from its use of existing resources and its general consistency with the Commission's guidance, SCE's proposed Demonstration Project D (and proposed schedule) is approved. SCE is instructed

to utilize EPIC funding to meet the non-procurement expenses; this Demonstration Project should have zero procurement costs.

3.2.3. SDG&E

SDG&E's proposed Demonstration Project D would be located at its Valley Center substation, which currently has a significant amount of DERs; in addition, SDG&E notes that it is in a rural location, which would allow for acquisition of land for additional DER equipment and facilities. (SDG&E June 17, 2016 Response, Attachment 1.)

ORA points out, however, that SDG&E apparently would need to procure significant additional DERs in the area in order to reach a high DER penetration level. (ORA August 26, 2016 Comments at 23.) ORA expressed the additional concern that SDG&E's plan would essentially create issues (caused by high DER penetration) that would have adverse impacts on customers served by the Valley Center substation, rather than using DER as a solution. (*Id.*)

TURN argues that SDG&E should not do Request for Offers (RFO) for its proposed Demonstration Project D, and that it could instead leverage Demonstration Project C and other already-funded projects. (TURN August 26, 2016 Comments at 6-8.) GPI similarly questions how SDG&E's proposed Demonstration Project D differs from its proposed Demonstration Project C. (GPI July 22, 2016 Comments at 17.)

As presented, SDG&E's proposed Demonstration Project D is not approved. SDG&E is directed to work with the staff of the Commission's Energy

Division to determine if the goals and objectives of Demonstration Project D could be addressed and accomplished through Demonstration Projects C and E.[6]

3.3. Demonstration Project E

The Scoping Memo for this proceeding described Demonstration Project E as follows:

> Demonstrate a microgrid where DERs (both customer-owned and utility-owned) serve a significant portion of customer load and reliability services. This project will demonstrate the use of a DER management system for controlling the resources. The project will develop, document, and implement a methodology for construction and operation/dispatch of the DER portfolio. The project will include both third-party-owned and utility-owned resources. (Scoping Memo at 8-9.)

3.3.1. PG&E

PG&E has proposed to use Angel Island as the location for its Demonstration Project E. Angel Island is an island in San Francisco Bay; in the past it received its bulk electric service via two 12 kV submarine cables, served from the Alto 1123 circuit, but one of the cables sustained unrecoverable damage and is no longer in service. (PG&E June 17, 2016 Revised Proposal at A-21.)

PG&E proposes to install a mix of wind and photovoltaic solar generation, combined with battery energy storage, demand response and energy efficiency, and propane generators for backup. (*Id.* at A-23-24.) PG&E states that it will own, operate, and maintain all of the equipment on Angel Island for Demonstration Project E. (*Id.* at A-24.)

[6] Demonstration Project E is for a microgrid, which will tend to have a high DER penetration level.

ORA raises some concerns with PG&E's proposed Demonstration Project E. First, ORA notes that:

> PG&E does not describe how the infrastructure on Angel Island, the DER sites, and load profiles are consistent with other probable microgrid locations, so it is not possible to determine the replicability of this project. (ORA July 22, 2016 Comments at 40.)

In addition, ORA argues that this Demonstration Project may be unnecessary, as it duplicates a pre-existing microgrid project:

> The issue of duplication of demonstration projects appears again for this project as PG&E is already a partner in a [California Energy Commission] CEC EPIC funded microgrid titled "Demonstrating a Community Microgrid at the Blue Lake Rancheria." (*Id.*)

According to ORA, the goals of the Blue Lake Rancheria microgrid are consistent with the Commission's guidance for Demonstration Project E. (*Id.*)

TURN also raises the duplication issue: "Specifically, PG&E proposes building a micro-grid on Angel Island, even though it has an existing microgrid at Santa Rita jail." (TURN July 22, 2016 Comments at 8.) According to TURN, PG&E has not explained why it cannot use an existing microgrid project for Demonstration Project E. (*Id.*)

PG&E disagrees with ORA and TURN on the duplication issue, but PG&E's Reply Comments did not really address their arguments or explain why its proposal here is not duplicative of one or more existing PG&E microgrid projects. (PG&E July 29, 2016 Reply Comments at 2.) At hearings, PG&E's witness did provide some testimony in response to the arguments of ORA and TURN, but it was not particularly detailed, and did not fully address the issues raised by ORA and TURN. (Transcript v. 1 at 25-30.)

The Scoping Memo in this proceeding called for Demonstration Project E to include both customer-owned (or third-party-owned) and utility-owned resources. (Scoping Memo at 8-9.) But PG&E states that it will own, operate, and maintain all of the equipment for Demonstration Project E. (PG&E June 17, 2016 Revised Proposal at A-24.) This is inconsistent with the direction of the Scoping Memo.

In addition, Marin Clean Energy submitted confidential material that raises additional concerns about the value of PG&E's Demonstration Project, and whether it would provide useful information for broader deployment of DERs. (Marin Clean Energy July 22, 2016 Comments at 3.)

Based on the facts presented and the goals of this proceeding, PG&E's proposed Demonstration Project E is not approved. If PG&E believes that an existing microgrid project can be used to satisfy the objectives of Demonstration Project E, PG&E may file and serve Comments within 45 days of the date of this decision requesting approval for a new Demonstration Project E, including a description of any modifications needed to the existing facilities. PG&E's filing should contain the same level of detail as provided for its original proposed location. Parties may file and serve Reply Comments no later than 30 days from the date of service of PG&E's Comments proposing a new Demonstration Project E.[7]

[7] While PG&E has 45 days to file Comments requesting approval for a new location, we encourage PG&E to file earlier (if possible), and to work with other parties to resolve any concerns about the proposed new location.

3.3.2. SCE

For its Demonstration Project E, SCE has proposed to deploy an inverter-only microgrid in a residential area adjacent to the University California, Irvine. (SCE June 17, 2016 Comments at 34; SCE July 29, 2016 Comments at 4.) SCE's arguments in support of its proposal include:

> The proposed location includes the area that hosted the Irvine Smart Grid Demonstration (ISGD) project, which was one of thirty two Department of Energy Regional Smart Grid Demonstrations funded through the American Recovery and Reinvestment Act. The Irvine location is attractive for several reasons, including:
>
> - Equipment installed and integrated during the ISGD project can be leveraged to accelerate the Project E schedule. Leveraging this equipment reduces cost and reduces schedule risk. […]
> - An existing array of resources (PV, storage) can be used for the demonstration, reducing cost.
> - Initial engagement shows hosting customer willingness to provide physical locations where SCE DER resources and control systems may be located. […] Therefore this location is likely to reduce cost and mitigate schedule risk. (SCE June 17, 2016 Comments at 38.)

SCE's proposed budget for its Demonstration Project E is $10.2 million, excluding procurement costs. (SCE June 22, 2016 Comments at 12-14.) This is significantly higher than the comparable cost estimates of PG&E ($4.2 million) and SDG&E ($500,000) for their Demonstration Project E proposals. The existing equipment only includes a small portion of the needed generation, and does not include other necessary equipment, so it is not clear that SCE has in fact gained significant cost savings from its choice of location.

In addition to its cost, the nature, location and duration of SCE's proposed Demonstration Project E also raised concerns. ORA identified a number of potential problems with SCE's proposal:

> One of the unique weaknesses of this project is that it does not appear to be located such that it serves a particular reliability need. A potential benefit of microgrids is added reliability and resiliency, and this assumes customers on the microgrid receive benefits that offset the additional costs of the microgrid. Nothing in SCE's proposal indicates that the 151 residential customers and one community center require more reliability or resiliency than SCE provides to its customers generally. The fact that SCE includes $850,000 for "maintenance and decommissioning" further suggests that the microgrid is not needed and that SCE does not intend to operate the system beyond this project. It does not appear that this location is representative of where microgrids would likely be deployed. (ORA July 22, 2016 Comments at 42.)

GPI similarly argues that SCE "misses the mark" with its Demonstration Project E proposal:

> SCE's Demonstration E project, which includes dismantling their microgrid, is planned for a location where a microgrid is unnecessary, will not provide any long-term insights into DER deployment and operation, and provides no lasting benefits to ratepayers. Given these and the following comments on Demonstration E, the GPI recommends rejecting SCE's Demonstration E project as currently proposed. (GPI July 22, 2016 Comments at 24.)

These criticisms of SCE's proposed Demonstration Project E are valid; accordingly, SCE's proposed Demonstration Project E is not approved. If SCE believes that an existing microgrid project can be used to satisfy the objectives of Demonstration Project E, SCE may file and serve Comments within 45 days of the date of this decision requesting approval for a new Demonstration Project E, including a description of any modifications needed to the existing facilities. SCE's filing should contain the same level of detail as provided for its original proposed location. Parties may file and serve Reply Comments no later than

30 days from the date of service of SCE's Comments proposing a new Demonstration Project E.[8]

3.3.3. SDG&E

For its Demonstration Project E, SDG&E has proposed to use an existing microgrid at its Borrego Substation, serving customers in Borrego Springs. (SDG&E June 17, 2016 Responses, Attachment A.) Because SDG&E is using an existing microgrid, its incremental costs for Demonstration Project E are $500,000.[9]

Other parties either support SDG&E's proposed Demonstration Project E or do not oppose it. (*See*, e.g., GPI July 22, 2016 Comments at 2.) Parties that addressed SDG&E's proposed Demonstration Project E generally indicated that they believe it is consistent with the Commission's guidance for Demonstration Project E. (*See*, e.g., TURN July 22, 2016 Comments at 9; ORA July 22, 2016 Comments at 38.) We agree, and also appreciate its low incremental cost to ratepayers. SDG&E's proposed Demonstration Project E is approved. Given that SDG&E is utilizing an existing microgrid, it will be possible to promptly obtain information from this project; accordingly, the schedule in Appendix A also applies to SDG&E's Demonstration Project E.

[8] While SCE has 45 days to file Comments requesting approval for a new location, we encourage SCE to file earlier (if possible), and to work with other parties to resolve any concerns about the proposed new location.

[9] SDG&E estimates a total of $14.7 million direct capital and DER procurement costs, with $14.2 million associated with existing and already funded capital projects and $500,000 in incremental unfunded costs. (SDG&E July 22, 2016 Comments, Attachment A at 3.)

3.4. Other Proposals

The Center for Sustainable Energy (CSE) also proposed a demonstration project. CSE's proposal is for integrating community and grid planning, and is designed to demonstrate how local governments and utilities could work together "to perform data-driven integrated DER planning in San Francisco…" (Ex. DRP2 – CSE1, Attachment at 1; see also July 21, 2016 Comments of CSE.)

Specifically, CSE proposes to facilitate data sharing and collaboration between PG&E and the City and County of San Francisco, and has requested federal Department of Energy (DOE) funding for its proposal. CSE's proposal does not include any DER deployment or procurement. (Transcript, v. 1, at 106-107.) The total cost of the CSE proposal is $389, 551, and CSE has requested $350,551 from DOE. As of the date of evidentiary hearings, DOE had not approved CSE's request for funding. (Transcript at 106.)

CSE is requesting funding for their proposed demonstration project by adding it to PG&E's request for rate recovery. In other words, however PG&E gets rate recovery for its demonstration projects, CSE asks that the cost of CSE's demonstration project be added to that, and PG&E would then pay CSE. (*Id.* at 108-112.) If CSE receives funding from DOE, the amount paid by PG&E ratepayers would be $39,000, the difference between the cost of CSE's proposal ($389,551) and the amount requested from DOE ($350,551). If CSE does not get funding from DOE, CSE is requesting that the total cost of its proposal ($389,551) be recovered from PG&E ratepayers. (Transcript at 110.)

While PG&E supported CSE's request for DOE funding (July 21 Comments of CSE, Attachment A), PG&E appeared to be surprised by CSE's request to recover its costs from PG&E ratepayers. (Transcript at 110-112.) In fact, CSE

appears to have first mentioned this approach for obtaining funding from PG&E ratepayers in its July 21 Comments. (Transcript at 110-111.)

The California Independent System Operator (CAISO) supports CSE's proposal, and enumerates possible benefits that the CAISO believes could be achieved from CSE's proposed demonstration project. (CAISO July 22 Comments at 1-5.) While the CSE proposal appears to be well-intentioned, it is not clear from the record of this proceeding that the CSE proposal will actually provide the specific benefits hoped for by the CAISO. Nor is it clear that PG&E or the other utilities cannot adequately collaborate and share data with local governments, or that CSE's proposal adds anything to the existing capabilities of the utilities or local governments (such as San Francisco, which is the subject of CSE's proposal).

We encourage the utilities to work with local governments to provide the potential benefits identified by the CAISO, and support the utilities' working with CSE if it obtains DOE funding. Nevertheless, CSE has not provided an adequate basis to support rate recovery from PG&E's ratepayers. Accordingly, we deny CSE's request for ratepayer funding of its demonstration project.

In its July 22, 2016 Comments, the Community Environmental Council (Council) offered suggestions for PG&E's and SCE's implementation of Demonstration Project A, and also recommended the adoption of a "Click and Claim demonstration project that would demonstrate an automated or partially automated Fast Track interconnection review process." (Council July 22, 2016 Comments at 8.)

Council described the implementation of its "Click and Claim" demonstration project:

> We are suggesting here that this "Click and Claim Demo" be an additional or alternative demonstration project for each of the

> IOUs OR an additional feature of one of the already-proposed demos, perhaps Demo A because that project focuses mostly on how to improve the ICA and, as SCE states, also how to best streamline Rule 21. (*Id.* at 11)

SCE opposes Council's "Click and Claim" proposal on the grounds that it is outside the scope of Track 2, as it does not relate to the Track 2 Demonstration Projects C, D and E, or to the issues being addressed in Track 2. (SCE July 29, 2016 Comments at 6.) In addition, SCE notes that Council's proposal was made after the deadline for proposing demonstration projects. (*Id.*)

SCE is correct. Council's proposal is not within the scope of Track 2, and was not proposed in a timely manner, giving other parties little opportunity to address its recommendations. Accordingly, Council's proposed demonstration project is not approved.

Bloom Energy proposed that Demonstration Project C should include projects that: "[D]emonstrate the benefits of a Bloom solid-oxide fuel cell placed in service on the IOU distribution system." (Bloom Energy June 17, 2016 Comments.) We are not requiring the utilization of any specific vendor's technology for Demonstration Project C. The utilities or third parties may utilize Bloom Energy (or other) fuel cells if they choose to, but are not required to do so. Bloom Energy's proposed demonstration project is not approved.

3.5. Process for Approval

Parties have made a range of suggestions for the solicitation process to be used in procuring DERs for the Demonstration Projects approved by this decision. SDG&E and ORA recommend the use of the Competitive Solicitation Framework (CSF) being addressed in the Commission's Integration of Distributed Energy Resources (IDER) proceeding, R.14-10-003. (SDG&E August 26, 2016 Comments at 2-3; ORA July 22, 2016 Comments at 5-6.)

The IDER pilot schedule incorporates an approval process taking 17 months before any additional DER projects commence construction. The IDER process, however, is designed to address a more initiatory situation than is present in this proceeding; here the Demonstration Projects and their locations have largely already been determined. Accordingly, it does not make sense to apply the full IDER schedule here, particularly given our interest in obtaining early results from the Demonstration Projects. For Demonstration Project C and SDG&E's Demonstration Project E we will use the schedule set forth in Appendix A, as discussed above, rather than the IDER schedule.

It does, however, make sense to adopt the relevant components of the CSF approved in the IDER proceeding for the purposes of Demonstration Project DER solicitations. Accordingly, we require all DER solicitations issued to utilize the grid services definitions and valuation components (Evaluation Methodology) set forth in the IDER Decision (D.) 16-12-036.

The IDER Decision on CSF and Regulatory Incentives addresses energy efficiency incrementality issues by having each utility propose and finalize a counting method from the five methods that came out of the CSF Working Group Final Report. (D.16-12-036 at 18-22.) For the purposes of the Demonstration Projects here, we direct the utilities to utilize the same methods they will use for the IDER Incentives Pilot. The Incentives Pilot's intent is to "mirror" Demonstration Project C; therefore, it makes sense to utilize the same methods here as outlined in the IDER decision.

Furthermore, we adopt 10 out of the 12 solicitation principles listed in the IDER Decision. These are:

- Principle 1: Framework meets the identified need on a least cost, best fit basis;

- Principle 2: Framework utilizes a competitive process with broad markets;
- Principle 3: Framework is technology neutral;
- Principle 4: Framework is transparent as allowed within confidentiality boundaries;
- Principle 5: Framework identifies a need without prejudging the technology;
- Principle 6: Framework does not limit the amount of any one type of technology;
- Principle 8: Framework is a fair and consistent process;
- Principle 9: Framework focuses on the identified need;
- Principle 10: Framework provides sufficient assurance of performance; and
- Principle 11: Framework allows for flexibility in the number and type of bids.

Solicitation Principles 7 (Framework is a streamlined process) and 12 (Framework includes a lessons learned feedback loop) are specific to the more extensive IDER process and are not readily applicable to the DRP Demonstration Project solicitations.

The utilities must demonstrate adherence to these 10 principles in their requests for contract approval. With regards to solicitation outreach, the utilities shall continue existing market outreach practices but should keep in mind the two-month window in the schedule in Appendix A, which is applicable to Demonstration Project C and SDG&E's Demonstration Project E.

ORA recommends that the Commission adopt a cap on procurement costs. (ORA July 22, 2016 Comments at 4; ORA August 26, 2016 Comments at 3-9.) ORA recommends a "soft" cap, which includes both non-procurement costs (as filed by the utilities) and procurement costs, that could be increased by the filing of a Tier 3 advice letter. (ORA August 26, 2016 Comments at 5-6.) Given that the

actual DER procurement costs (and their corresponding rate impacts), are currently unknown, this seems to be a reasonable precaution to take in order to protect ratepayers from potentially high costs. ORA's cap is based on a formula, and the level of the cap would be confidential to further protect ratepayers. We adopt ORA's cost cap proposal.

As discussed above, the non-procurement costs for SCE's Demonstration Project C have been reduced to $3 million (from SCE's original proposal of $9.3 million); the ORA-recommended cost cap is therefore reduced by a corresponding amount.

For SDG&E's Demonstration Project C, ORA stated: "Unlike the other utilities, SDG&E declined to provide ORA with information regarding any traditional wire solutions which could be deferred by its proposed Demo C project…" (ORA August 26, 2016 Comments at 16.) As a result, ORA could not calculate a cost cap for SDG&E's Demonstration Project C. Because of this, ORA: "[R]ecommends that the Commission require SDG&E to provide cost information on the deferral value of its proposed Demo C Project so a reasonable budget cap can be established for this project." (*Id*. at 16-17.)

We agree with ORA's recommendation. SDG&E is directed to work with the Commission's Energy Division to develop a cost cap for its Demonstration Project C, using the same method used by ORA for the other cost caps (taking into consideration that we have already removed $4.6 million from SDG&E's non-DER procurement budget). SDG&E will submit a Tier 2 Advice Letter within 30 days of approval of this decision to set the soft cost cap and justify the costs associated with the proposed DER procurement.

We also adopt ORA's proposal for the utilities to file a Tier 3 Advice Letter to increase the cost cap.

ORA recommends that the results of solicitations be reviewed and approved by application, rather than advice letter, in large part due to uncertainties around the solicitation process. (ORA August 26, 2016 at 9-10.) Given the steps we have taken above (the adoption of certain elements of the IDER CSF and the cost cap), this appears to be unnecessary. Accordingly, the utilities may submit their requests for the approval of contracts coming from the solicitations via Tier 3 Advice Letter.[10] The Tier 3 Advice Letters to approve the contracts shall explain the utilities' solicitation process and include contract information. Stakeholder input with respect to solicitations will focus on how bids were evaluated and selected, and will come through protests and responses to the Tier 3 Advice Letters. The Advice Letter should also state the reasons new DER is needed—the utilities should provide a comprehensive list of existing DER within the demonstration projects, identify them as third-party or utility-owned, justify why new DER is needed and how existing DER is not capable of meeting project goals and objectives, and state the value of any deferred investments.[11]

Several parties (e.g., Solar City, Clean Coalition, Vote Solar, TURN, ORA) argue that the utilities should leverage existing DER or existing RD&D projects before procuring new DER. We agree. The utilities should leverage use of existing third-party systems to manage DER resources, and should utilize capabilities of existing DER before procuring new DER for the demonstration projects.

[10] SDG&E must submit its Tier 2 Advice Letter to set the cost cap for its Demonstration Project C prior to submitting an Advice Letter for contract approval for Demonstration Project C.

[11] To the extent this information is confidential, the utility may include it in a confidential attachment.

As Clean Coalition argued, the process should make "[I]mmediate initial use of utility owned facilities and existing third party facilities in demonstration project design, followed by incremental addition of additional third party facilities." (Clean Coalition July 22, 2016 Comments at 6.) Similarly, Vote Solar is correct that the: "[D]emonstration projects provide an ideal environment to evaluate if third-party dispatched resources can provide reliable, consistent response to utility signals, and if reliance on third-party controlled DER and third-party owned communications infrastructure is more cost effective." (Vote Solar August 26, 2016 Comments at 4.)

The utilities should provide a clear basis for any reliance on utility-owned assets, and accordingly the utilities are directed to do a side-by-side comparison of the costs and cost-effectiveness of third-party and utility-controlled DER alternatives, and should also explain how the DER portfolio was chosen. This information is not required to be provided in the Advice Letters seeking contract approval, but will be required to be provided in the reports to be submitted to the Commission, as described in Appendix A.

The utilities have proposed several metrics to assess Demonstration Project performance; several of these metrics overlap across multiple projects, while others are project-specific. While the metrics proposed by PG&E and SDG&E are relevant, SCE's proposed metrics are a good starting point to assess project performance. To ensure consistent evaluation of the projects across the utilities, the tables in Appendix B summarize the metrics to be used to assess project performance for each of the demonstration projects.

SCE and PG&E proposed ratemaking treatments for the costs to implement the Demonstration Projects.

SCE proposed that this decision should approve the budget and authorize cost recovery for SCE's O&M expenses and capital expenditures, direct SCE to file a Tier 2 advice letter to open a DRP Demonstration Balancing Account to record the revenue requirement associated with the demonstration project, and direct SCE to file an annual Tier 3 Advice Letter to recover the prior year's under-collected balance. For approval of contracts for third-party DER resources, SCE would conduct an RFO and submit a Tier 3 Advice Letter seeking approval for each contract. (SCE June 17, 2016 Comments at 13-14.)

PG&E described its ratemaking proposal:

> For recovery of the incremental costs associated with its DRP Demonstration Program, PG&E requests that the Commission authorize PG&E to include in electric distribution rates the forecast revenue requirements associated with the demonstration projects described below beginning January 1, 2017. PG&E requests that the Commission authorize PG&E to establish the Distribution Resources Plan Demonstration Program Balancing Account (DRPDPBA), which is a one-way balancing account, to record and track the authorized revenue requirements compared to the revenue requirements associated with actual costs, including expense and capital. Upon conclusion of the Projects, any unspent funding in the tracking account would be returned to customers by transferring the balance to the Distribution Revenue Adjustment Mechanism (DRAM) as part of PG&E's Annual Electric True-up (AET) process. (PG&E June 17, 2016 Comments at A-1 – A-2.)

These proposals are mostly similar, although we prefer PG&E's proposed one-way balancing account. SCE's name (and corresponding acronym) for the balancing account is slightly shorter, so we will adopt that name (DRP Demonstration Balancing Account) rather than PG&E's. Otherwise, we approve PG&E's proposed process for all three utilities. Utilities may only record incremental procurement- and non-procurement-related O&M expenses and

capital expenditures in the DRP Demonstration Balancing Account, and not overheads or Administrative and General expenses that would otherwise be approved in a General Rate Case.

4. Categorization and Need for Hearing

Track 2 of these consolidated proceedings is categorized as ratesetting. The Scoping Memo determined that hearings may be needed; hearings were requested by ORA, and were held on August 10 and 11, 2016.

5. Comments on Proposed Decision

The proposed decision of Administrative Law Judge (ALJ) Allen in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by PG&E, SCE, SDG&E, ORA, TURN, GPI, and Community Environmental Council (Council). Reply comments were filed by PG&E, SCE, SDG&E, ORA, TURN, Solar Energy Industries Association and Vote Solar, Clean Coalition, and Solar City Corporation (Solar City). All comments and reply comments were considered, and corresponding changes have been made to the proposed decision.

In its comments on the proposed decision, PG&E states that its proposed location for Demonstration Project C is no longer viable due to "reduced equipment loadings," and requests authorization to submit a revised Demonstration Project C at a new location. (PG&E Comments on PD at 2.) Similarly, SDG&E in its comments states that because of a change in forecasted thermal overload, Circuit No. 470 (one of two circuits proposed by SDG&E for Demonstration Project C) no longer fits the criteria for Demonstration Project C. (SDG&E Comments on PD at 5.) The decision has accordingly been changed to no longer approve these two proposed locations for Demonstration Project C,

and to incorporate a process for PG&E and SDG&E to propose new locations for Demonstration Project C. This process includes a webinar, as recommended by Solar City. (Solar City Reply Comments on PD at 3.)

SCE requested that the Demonstration Project C non-procurement cost cap of $2 million proposed for Equipment and Services be removed, leaving in place just the $3 million cost cap for all non-procurement costs. (SCE Comments on PD at 2-3.) That change has been made.

PG&E made an argument that it does not actually need to comply with this decision if the Commission does not grant PG&E specific approvals in the future:

> PG&E understands that the PD's approval of the "soft cost cap" for procurement and non-procurement costs proposed by the Office of Ratepayer Advocates (ORA) means that any approval to exceed the "soft cost cap" will need to be requested in a Tier 3 advice filing. (PD, Ordering Paragraph 19.) However, PG&E also understands that the Commission will provide up-front review and approval of the forecast project costs in the Tier 3 advice filing that seeks approval of the demonstration project contracts. (PD, Ordering Paragraph 22.) As such, PG&E's demonstration project contracts will be conditioned on Commission up-front approval of the full contract costs and prices over the term of the contract. If the Commission does not approve the contract costs and pricing, PG&E will not proceed with the contract as negotiated and instead will reopen and/or renegotiate the contract or DER solicitation to procure DERs that comply with the Commission's cost authorization. Alternatively, PG&E will not proceed with the demonstration projects. (PG&E Comments on PD at 3.)

PG&E's argument is in direct violation of a Commission decision, D.16-09-004, which stated in a section entitled "Admonishment to PG&E":

> PG&E's agreement includes a term that the Seller has no stake in (i.e., cost recovery), but which results in PG&E's ability to terminate the agreement based solely on Commission action. We do not approve this constraining term within the contracts and

> caution PG&E that in the future it should refrain from establishing contract terms designed to limit the Commission's exercise of its regulatory authority. (D.16-09-004 at 24.)

We expect PG&E to comply with Commission decisions. Failure to comply with Commission decisions may result in the imposition of penalties under Public Utilities Code section 2107. (*See*, e.g., D.02-04-018.) PG&E's attempt to place conditions on its compliance with this decision is rejected.

SCE requested clarification on the operation of the balancing account and related ratemaking:

> SCE understands the PD directs it to create a new one-way balancing account to record incremental demonstration project related Operation and Maintenance expenses, as well as, any capital related revenue requirement (e.g., depreciation, return on rate base, property taxes, and income taxes) associated with any DER demonstration-related capital projects SCE owns and operates. Because the PD requires a spending cap, SCE will operate this new one-way balancing account over the entire three-year period of the demonstration project and will only collect in rates costs up to the $3 million cap pursuant to the PD. SCE will use the balancing account to record the incremental O&M and capital revenue requirement up to the $3 million cap. At the end of the third year, SCE will transfer no more than the $3 million to the distribution subaccount of the Base Revenue Requirement Balancing Account (BRRBA) for recovery in distribution rates. Any on-going revenue requirement associated with any capital expenditures, will continue to be recorded in the BRRBA until it is rolled into SCE's General Rate Case revenue requirement.
>
> SCE also believes the PD requires that any third-party energy and capacity procurement costs incurred as part of approved demonstration project procurements to be recovered through normal procurement processes (e.g., advice letters and the ERRA process) as authorized by the Commission, and that these procurement costs will not be recorded in the newly established one-way balancing account. (SCE Comments on PD at 7.)

This clarification is reasonable, and no party objected to it in reply comments. We agree with this clarification.

PG&E, SCE and SDG&E all request a less-accelerated schedule for Demonstration Project C[12]; the schedule in Appendix A has been modified to provide somewhat more time and flexibility for compliance.

ORA argued that:

> The PD should be modified to make clear that any subsequent IOU proposals for Demonstration Projects D and E should answer the questions outlined for DRP Revised Project Proposals in Appendix A of the May 17, 2016 ACR, as well as comply with the January 27, 2016 Scoping Memo requirements for Demonstration
>
> Projects C, D, and E. (ORA Comments on PD at 3.)

The other parties, including the utilities, generally agreed with (or did not oppose) these requirements. It makes sense that any new proposals should meet the same criteria and provide the same amount of information as the original proposals that they replace. The decision has been revised to reflect this requirement.

Solar City requested clarification that existing net energy metering (NEM) and Self Generation Incentive Program (SGIP) projects can be used for incremental distribution services for the Demonstration Projects authorized by this decision, and that they are eligible to participate in the solicitation process for the approved Demonstration Projects. (Solar City Reply Comments on PD at 3-5.) This is consistent with the general approach we take here, that existing DERs should be used for the Demonstration Projects, so we clarify that NEM and

[12] SCE also requests a slower schedule for Demonstration Project D.

SGIP projects may be used for incremental distribution services for approved Demonstration Projects.

Council noted that the Proposed Decision did not address Council's proposed "Click and Claim" demonstration project. The decision has been revised to address Council's proposed demonstration project.

6. Assignment of Proceeding

Commission President Michael Picker is the assigned Commissioner and Peter V. Allen and Robert M. Mason III are the assigned ALJs in this proceeding.

Findings of Fact

1. The proposed location for PG&E's Demonstration Project C is no longer viable.
2. SCE's Demonstration Project C is in a reasonable location.
3. SCE's proposed budget for its Demonstration Project C is significantly too high.
4. SDG&E's Demonstration Project C on Circuit 701 is in a reasonable location.
5. SDG&E's Demonstration Project C on Circuit 470 no longer fits the criteria for Demonstration Project C.
6. SDG&E's proposed use of $4.6 million for utility-owned energy storage as part of its Demonstration Project C is not appropriate.
7. The utilities' proposed schedules for Demonstration Project C are too slow, and would unnecessarily delay the availability of information from Demonstration Project C.
8. PG&E's Demonstration Project D is generally consistent with the Commission's guidance and has reasonable costs.

9. SCE's Demonstration Project D is generally consistent with the Commission's guidance and has reasonable costs.

10. SDG&E's Demonstration Project D, as proposed, does not provide adequate net benefits.

11. PG&E's Demonstration Project E is not consistent with the Commission's guidance, and presents other potential problems.

12. SCE's Demonstration Project E does not provide adequate net benefits.

13. SDG&E's Demonstration Project E is in a reasonable location and has reasonable costs.

14. The Center for Sustainable Energy's proposed demonstration project does not provide adequate net benefits.

15. Council's proposed "Click and Claim" demonstration project is outside the scope of Track 2 of this proceeding, and was proposed after the deadline for proposing demonstration projects.

16. Bloom Energy's proposed demonstration project is not consistent with the Commission's guidance.

17. The Commission recently adopted D.16-12-036 in the IDER proceeding, aspects of which are applicable to the subject of this proceeding.

18. A cost cap including both procurement and non-procurement costs would help ensure that the costs of the Demonstration Projects are reasonable.

19. Utilities should obtain Commission approval for their procurement of Demonstration Project contracts.

20. The Demonstration Projects are intended to provide information that can be used in the deployment of DER.

21. Information about the Demonstration Projects should be comparable across utilities.

22. The reasonable costs of the Demonstration Projects are recoverable in utility rates.

Conclusions of Law

1. PG&E's Demonstration Project C should not be approved.
2. SCE's Demonstration Project C should be approved, but with a significantly reduced budget.
3. SDG&E's Demonstration Project C on Circuit 701 should be approved, but with the removal of the proposed $4.6 million of utility-owned energy storage.
4. SDG&E's Demonstration Project C on Circuit 470 should not be approved.
5. Demonstration Project C should be implemented on an accelerated schedule.
6. PG&E's Demonstration Project D should be approved.
7. SCE's Demonstration Project D should be approved.
8. SDG&E's Demonstration Project D should not be approved.
9. PG&E's Demonstration Project E should not be approved.
10. SCE's Demonstration Project E should not be approved.
11. SDG&E's Demonstration Project E should be approved.
12. The Center for Sustainable Energy's proposed demonstration project should not be approved.
13. Council's proposed demonstration project should not be approved.
14. Bloom Energy's proposed demonstration project should not be approved.
15. Applicable provisions of D.16-12-036 should be used here.
16. A cost cap including both procurement and non-procurement costs should be adopted for the Demonstration Projects.
17. Utilities should be required to submit their requests for approval of Demonstration Project contracts via Tier 3 Advice Letters.

18. Reports to the Commission regarding the Demonstration Projects should be required.

19. Common metrics should be applied to the Demonstration Projects.

20. Rate recovery for the reasonable costs of the Demonstration Projects should be approved.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company's Demonstration Project C is not approved.

2. Pacific Gas and Electric Company shall file and serve Comments within 30 days of the date of this decision requesting approval for a new Demonstration Project C. Pacific Gas and Electric Company shall present a webinar on the details of its new location, noticed to the service list, no later than 20 days from the date of this decision. Other parties may file and serve Reply Comments no later than 30 days from service of the Comments proposing a new Demonstration Project C.

3. Southern California Edison Company's Demonstration Project C is approved with a total non-procurement budget of $3 million.

4. San Diego Gas & Electric Company's Demonstration Project C for Circuit 701 is approved with the removal of utility-owned storage and a corresponding budget reduction of $4.6 million.

5. San Diego Gas & Electric Company's Demonstration Project C for Circuit 470 is not approved.

6. San Diego Gas & Electric Company shall file and serve Comments within 30 days of the date of this decision requesting approval for a new location for Demonstration Project C. San Diego Gas & Electric Company shall present a webinar on the details of its new location, noticed to the service list, no later than 20 days from the date of this decision. Other parties may file and serve Reply Comments no later than 30 days from service of the Comments proposing a new location for Demonstration Project C.

7. The schedule for implementation of Demonstration Project C is set forth in Appendix A to this decision.

8. Pacific Gas and Electric Company's Demonstration Project D is approved.

9. Southern California Edison Company's Demonstration Project D is approved.

10. San Diego Gas & Electric Company's Demonstration Project D is not approved.

11. San Diego Gas & Electric Company is directed to work with the staff of the Commission's Energy Division to determine if the goals and objectives of Demonstration Project D could be addressed and accomplished through Demonstration Projects C and E.

12. Pacific Gas and Electric Company's Demonstration Project E is not approved.

13. Pacific Gas and Electric Company may file and serve Comments within 45 days of the date of this decision requesting approval for a new Demonstration Project E using an existing microgrid project. Other parties may file and serve Reply Comments no later than 30 days from service of the Comments proposing a new Demonstration Project E.

14. Southern California Edison Company's Demonstration Project E is not approved.

15. Southern California Edison Company may file and serve Comments within 45 days of the date of this decision requesting approval for a new Demonstration Project E using an existing microgrid project. Other parties may file and serve Reply Comments no later than 30 days from service of the Comments proposing a new Demonstration Project E.

16. San Diego Gas & Electric Company's Demonstration Project E is approved.

17. The schedule for implementation of San Diego Gas & Electric Company's Demonstration Project E is set forth in Appendix A to this decision.

18. The Center for Sustainable Energy's request for ratepayer funding of its proposed demonstration project is not approved.

19. Community Environmental Council's proposed demonstration project is not approved.

20. Bloom Energy's proposed demonstration project is not approved.

21. All utilities should use applicable provisions of Integrated Distributed Energy Resources Decision 16-12-036, particularly the grid services definitions, valuation components, and counting methods.

22. The recommendation of the Office of Ratepayer Advocates for the adoption of a soft cost cap including both procurement and non-procurement costs is adopted.

23. An increase in the level of the cost cap can be requested by filing a Tier 3 advice letter.

24. San Diego Gas & Electric Company is directed to work with the Commission's Energy Division to develop a cost cap for its Demonstration Project C.

25. San Diego Gas & Electric Company will submit a Tier 2 Advice Letter within 30 days of approval of this decision to set the cost cap for its Demonstration Project C.

26. The utilities must submit their requests for the approval of Demonstration Project contracts via Tier 3 Advice Letter.

27. The utilities are required to file reports on the status of their Demonstration Projects as set forth in Appendix A.

28. All reports and compliance filings ordered by this decision shall be submitted to Energy Division's Central Files as well as served via email on the service list of this proceeding. The utilities shall follow the current guidance from the Energy Division about submitting documents to Energy Division's Central Files. Energy Division's Central Files may be contacted by email at energydivisioncentralfiles@cpuc.ca.gov.

29. The metrics to be used to assess Demonstration Project performance are set forth in Appendix B to this decision.

30. The utilities are authorized to establish a one-way "DRP Demonstration Balancing Account" to record and track the authorized revenue requirements compared to the revenue requirements associated with actual costs, including expense and capital. Unspent funding in the account will be returned to customers by transferring the balance to the Distribution Revenue Adjustment Mechanism or an equivalent account.

31. The utilities may only record incremental procurement- and non-procurement-related Operations and Maintenance expenses and capital expenditures in the Distribution Resources Plan Demonstration Balancing Account, and not overheads or Administrative and General expenses that would otherwise be approved in a General Rate Case.

This order is effective today.

Dated February 9, 2017, at San Francisco, California.

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners

APPENDIX A

Reporting Requirements and Schedule for Demonstration Project C and E

Reports Staff distinguishes between: (1) reports that inform the Commission on the status of the projects, such as if there are delays in implementing the projects or status of construction (Project Status Reports); and (2) reports that analyze data of DER performance once the project commences (Project Data Reports). The schedule below only lists when the Project Data Reports are due. This reporting schedule for the Project Data Reports will apply to Demonstration Projects C and E.

The reporting format shall be as follows:

Project Status Reports

The utilities are required to file information-only reports, after approval of the contracts, updating the Commission on the progress of the project deployment and any obstacles that may delay the start of data gathering. The first report should be 3 months after approval of the contracts, and 3 months apart thereafter and lasting until completion of construction and notifying the commission when data gathering will start. The utilities are instructed to work with Energy Division on the content of these reports, but at a minimum they should contain the status of the project, relevant changes or modifications to the schedule and updating any milestones, challenges encountered, and solutions posed. The utilities shall also explain how the DER portfolio was chosen.

Project Data Reports

The data gathering phase of the projects will contain three reports, as outlined in the schedule. These reports shall be filed as Information-Only filings. The reports are divided such that the first report will analyze the first three months of data, the second report the following six months, and the last report the last three months of data gathering along with a cumulative report on the entire year. In general, the utilities have two months to analyze the data and file the report. The utilities should provide a clear basis for any reliance on utility-owned assets, and accordingly the utilities are directed to do a side-by-side comparison of the costs and cost-effectiveness of third-party and utility-controlled DER alternatives. The reports should also include any challengers and changes in circumstances that delayed data gathering/analysis and solutions taken.

The following table outlines the schedule for Demonstration Project C and SDG&E's Demonstration Project E.

Month	Action	Action
	(Need for new DER is determined)	**(No need for new DER)**
1	• Commence Project & Identify need for New DER and Prepare Solicitation Material • Solicitation of new DER and filing of Tier 3 Advice Letters for approval of contracts	Commence Project & Identify need for New DER
2		
3		Testing of Operations
4		
5		Projects Commence (Data Gathering)
6		
7		
8		
9		
10		1st Progress Report Filed (Months 5, 6, 7)
11	CPUC Approval (2 months max)	
12		
13	Construction of new DER	
14		
15		
16		Data Gathering Ends & 2nd Progress Report (Months 8 through 13)
17		
18		
19	Testing of Operations	3rd (Months 14 through 16) and Cumulative Progress Report
20		
21	Projects Commence (Data Gathering)	
22		
23		
24		
25		
26	1st Progress Report Filed (Months 21, 22, 23)	
27		
28		
29		
30		
32	Data Gathering Ends & 2nd Progress Report (Months 24 through 29)	
33		
34		
35	3rd (Months 30 through 32) and Cumulative Progress Report	

(End of Appendix A)

APPENDIX B

To ensure consistent evaluation of the projects across the utilities, the following tables summarize the metrics to be used to assess project performance for each of the demonstration projects.

Metrics for Demonstration Projects C and D

Demonstration C and D: DER Performance Metrics	
Performance Measure	**Description**
DER Capacity Output	Measure the DER capacity output for one year or greater, to compare to the forecasted output prior to procurement
DER Energy Output	Measure the DER energy output for one year or greater, to compared to forecasted energy output prior to procurement
Local Utility System Voltage	Measure the utility system voltage for one year or greater, at a point in proximity to the DER installation and compare to a year prior to DER installation
Utility Circuit Load	Measure the utility circuit load for the circuit which hosts the DER, for one year or greater, and compare to a year prior to DER installation
Utility Circuit Energy	Measure the utility circuit energy delivery for the circuit which hosts the DER, for one year or greater, and compare to a year prior to DER installation
Utility to DER Dispatch Request	Measure the ability of the DER to respond to utility requests when called upon to provide distribution services and solve a local grid/system need.
Utility system energy mix	Measure the utility's energy delivery mix, such that appropriate GHG emission offsets can be evaluated and compared with the DER, while the DER is in service
DER Project capacity factor	Measure the ratio of the actual output power to its full nameplate capacity over a period of time (usually one year).
DER Project Capacity cost	Unitize the actual cost of a DER to provide capacity per unit of time
DER Project Energy cost	Unitize the actual cost of a DER to provide energy per unit of time.
DER Reactive Power Output	Measure the DER reactive power output for one year or greater, to study the ability of the resource to supply reactive power
Distribution Capacity and Hosting Capacity Service Effectiveness	Measure the technical effectiveness of DER dispatch with mitigating projected equipment overloads. Comparative analysis will be performed evaluating projected equipment loading levels against actual equipment loading levels and conditions when sourced DER

	portfolio is dispatched
DER Readiness & Assurance	Measuring the time between contract award to operation to ensure timeliness in meeting the locational needs. Measuring the communication reliability between PG&E dispatch operators and the aggregator owned DER equipment. Ensure that DER readiness is available when expected to contribute to the grid needs and utility reserved periods pending contract arrangements.
Process Evaluation	A process evaluation study performed by a third party expert to be made public describing the end to end process of Project C implementation and suggesting enhancements to the future DER deployments with similar use cases. The process evaluation will critique the end to end process and provide suggestions for improvements in development of least-cost/best-fit DER portfolios and the sourcing of those portfolios. The process evaluation will also estimate the overall cost-effectiveness of the project and make recommendations on how overall cost-effectiveness can be approved in future deployments.
Point of Common Coupling Voltage Support	Measure the voltage increase/decrease seen at the PCC due to the DER operation.
Turn Around Efficiency	Measure the overall energy lost (%) from storage and utilization of energy.
DER Operational Mode Validation	Verify the DER solution modes of operation, such as peak shaving, operate as expected.

Demonstration C and D: Smart Device/Intelligent Electronic Devices Performance Metrics	
Performance Measure	**Description**
DER Real Power Output	Measure the real power (kW)output of the DER solution compared to the nameplate rating.
DER Reactive Power Output	Measure the reactive power (kVAR) output of the DER solution compared to the nameplate rating.
Communication Latency	Latency between issued command to actual operation will be measured.
Communication resiliency	Communication failures and signal loss will be measured.
Point of Common Coupling Voltage Support	Measure the voltage increase/decrease seen at the PCC due to the DER operation.
Effectiveness of proposed autonomous operations	Proposed autonomous solutions effectiveness such as automated Volt/VAR operations should be compared to simulated results.

Additional Metrics for Demonstration Project C

Demonstration C: Additional Performance Metrics	
Performance Measure	**Description**
LNBA Validation	An evaluation, measurement and verification (EM&V) study performed by a third party expert to be made public suggesting enhancements to the LNBA model estimates that address any identified gaps between estimated LNBA and the observed results from Project C.

Additional Metrics for Demonstration Project D

Demonstration D: Additional Performance Metrics	
Performance Measure	**Description**
DER Penetration	Measure of the amount of DER generation (power) divided by the peak circuit or area demand expressed as a percentage
Voltage Controlability	Comparison between the voltage setpoint and local utility system voltage measurement
Power Flow Controlability	Comparison between the power flow setpoint and utility circuit load measurement
Control and Data Management	Measure the time it takes to gather, process, make recommendation to operator and execute on a command.

Metrics for Demonstration Projects E

Demonstration D: Additional Performance Metrics	
Performance Measure	**Description**
Island Reliability	Track transitions to and from island mode and during island mode operation; traditional electric utility metrics of momentary outage frequency, sustained outage frequency and sustained outage duration will be used
Island Power Quality	Measure and compare total harmonic distortion (THD), voltage sags and swells, through transitions to and from island mode and during island mode operation.
Island Duration	Measure that the minimum island duration requirement of 2 hours has been met
DER Capacity Output	Measure and verify how much DER (3rd party and other) power was utilized to meet the island duration requirement
DER Energy Output	Measure and verify how much DER (3rd party or other) energy was utilized to meet the island duration requirement
Local Utility System Voltage	Measure the utility system voltage during island mode

	operation
Utility Circuit Load	Measure the utility circuit load for the circuit which hosts the DER during island mode operation
Utility Circuit Energy	Measure the utility circuit energy delivery for the circuit which hosts the DER during island mode operation
Utility to DER Dispatch Request	Measure the ability of the DER to respond to utility requests when called upon to support the microgrid.
Island Voltage	Measure the island's voltage during island mode operation
Customer Feedback	Through surveys and/or interviews customers will rate their experience in participating in the demonstration with respect to making resources available to the microgrid, any inconveniences experienced as a result of microgrid operations, and customer service levels provided by SCE and 3rd parties
Microgrid Service Effectiveness	Measure the effectiveness of DER dispatch with respect to meeting the microgrid loads
Microgrid Readiness & Assurance	Measuring the communication reliability between PG&E dedicated microgrid controller and the third-party owned DER equipment. Ensure that DER readiness is available when called upon during emergency services and when meeting real-time load changes. Also, measuring the reliability of protective relaying that will sense an external grid disturbance and island the microgrid
Process Evaluation	A process evaluation study performed by a third party expert to be made public describing the end to end process of Project E implementation and suggesting enhancements to the future DER deployments with similar use cases. This process evaluation will also critique and provide suggestions for improvements in the process of developing least-cost/best-fit DER portfolios and the sourcing of those portfolios

(End of Appendix B)